1-1.2.6 Location of fluids in oil and gas reservoirs

A) Accumulation of hydrocarbon in the reservoirs (secondary migration)

a) Overview on secondary migration

The hydrocarbons, produced in generally shaly, low-permeability source rocks, are expelled from these rocks during a process which is still poorly understood and in which compaction could play a major role. This phase is known as primary migration. We will restrict ourselves here to secondary migration, i.e. transport of hydrocarbons in permeable layers and trapping in the reservoirs. Capillarity plays a central role in these phenomena.

To describe this secondary migration, we can make the assumption that the permeable layers acting as drain or reservoir are strongly water-wet. These rocks, in fact, remained saturated with water for a considerable period of time before being placed in contact with the hydrocarbons. They are therefore water-wet, at least during the first phase of hydrocarbon accumulation. This phase will be described here (see § 1-2.2, p. 173, regarding the possible acquisition of oil wettability).

	d by S_{wi} "*a priori*"	Use of the Leverett transform and the S_w values normalised by S_{wi} "*a priori*", in the most general case
'Generalised Thomeer' method	Often used after transformation into Pc_{res} and into S_w normalised by S_{wi} "*a priori*"	Rarely used, special cases

Hydrocarbons are driven to move by their "buoyancy" which is related to the difference in density ($\Delta\rho$) between hydrocarbons (ρ_o, ρ_g) and water (ρ_w). This force is used to overcome the capillary barrier (capillary pressure) opposing the penetration of non-wetting fluid. At the top of a hydrocarbon column of height h, the buoyancy induces a pressure difference with respect to water ($\Delta P = Po - Pw$) which is easy to calculate using the fluid equilibrium formula: $\Delta P = \Delta\rho \,.\, \gamma \,.\, h$, where γ is the gravitational acceleration (see paragraph § B. a below for further details).

Movement of the hydrocarbons therefore implies coalescence into accumulations whose height is sufficient to overcome the capillarity (see below § B. a for orders of magnitude). These accumulations will move upwards along the upper limits of the layers, or more precisely the permeability-capillarity contrasts. These contrasts may represent relative barriers which will be crossed when the height of the oil column has increased due to influx of additional hydrocarbons. These contrasts may also correspond to absolute barriers if the permeabilities are extremely low (compacted shale). This is the case of cap rocks which may lead to the formation of a reservoir if the geometry of the impermeable rock allows a trap to develop.

If the geometric structure forms a trap, the hydrocarbons accumulate (from the top towards the bottom of the trap). If the hydrocarbon influx is sufficient the geometric spill point (Fig.1-150a), corresponding to the lowest point of the trap, may be reached. The reservoir is full; the distance between the highest point of the trap and this spill point is called the trap "closure".

b) Capillary trapping (residual saturation) and traces of secondary migration

The notion of residual saturation caused by capillary trapping of a fraction of non-wetting fluid is defined in § 1-1.2.2.D, p. 59. At the end of the secondary migration, when there is no further influx of hydrocarbons, this residual saturation should last in the transfer zones, showing the path of the secondary migration.

Over the course of geological time, one might expect that the progressive disappearance of residual fluids, especially gases, is due to solubilisation (if there is water movement in the layer) or diffusion phenomena. As regards oil, an evolution into bituminous formations (tar-mats) is more likely.

What is the true situation? It is extremely difficult to provide an objective answer. It seems almost impossible to detect such traces of residual hydrocarbons, in fact, since they would be limited to relatively thin layers of rock in contact with permeability contrasts. Located by definition outside reservoirs, there is very little chance of samples being taken from this type of zone during coring. In addition, it is very difficult to detect by log analysis. We therefore see how difficult it is to provide an answer.

The notion of residual hydrocarbon also arises when, under the effect of tectonic movements (e.g. tilting), the reservoir closure decreases (relative elevation of the spill point) and the trap partly empties. In this case, any residual traces are easier to locate. It is likely, however, that there is a link between this residual fraction and the tar-mats sometimes present in large quantities below the current oil/water contacts. It is also highly probable that this phenomenon contributes to the uncertainty regarding the exact location of the oil/water contact surfaces often observed in practice.

B) Capillary equilibria and location of fluids in a reservoir

a) Evolution of capillary pressure in a reservoir according to depth

We have briefly outlined the accumulation of hydrocarbons in reservoirs. We will now examine the distribution of fluids in a reservoir at equilibrium. We will start from the following situation: we observe the coexistence in the reservoir of two fluids in continuous masses, one strongly wetting, water, the other non-wetting, oil (or gas).

Each fluid individually respects the law of hydrostatics, the pressure depending on the depth D and the density ρ:

$$P_w = \rho_w \gamma D + C_1 \text{ et } P_o = \rho_o \gamma D + C_2,$$

where C1 and C2 are adjustment constants.

Expressed in the coordinate system D against P (Fig. 1-1.50a), the two straight lines of different gradients intersect at a depth D_e such that $P_w = P_o$. The level corresponding to this depth plays an important role in the expression of capillary equilibrium. It is called the Free Water Level. We will use the abbreviation FWL. By knowing D_e we can determine the values of the adjustment constants C_1 and C_2 since at this depth.

$P_o = P_w$ and therefore $C_1 - C_2 = \Delta\rho\gamma D_e$ (where $\Delta\rho = \rho_w - \rho_o$).

Introducing a new depth variable, the height h above FWL.

($h = D_e - D$), we immediately obtain:

$\Delta P = P_o - P_w = \Delta\rho\gamma h$.

By definition, however, the capillary pressure Pc is equal to $P_o - P_w$. We therefore obtain the well-known equation.

$Pc = \Delta\rho\gamma h$, which provides a direct relation between the saturation in a reservoir and the capillary pressure curve.

b) Saturation distribution in a homogeneous reservoir

For a reservoir which is assumed to be perfectly homogeneous, the above formula immediately gives the saturation distribution from the capillary pressure curve $Pc = f(S_w)$, by making a change of variable on the y-axis. h can be substituted for Pc, since $h = Pc/\Delta\rho\gamma$.

Obviously, this logic is only quantitatively valid if the capillary pressure curve was measured with a pair fluids identical to those of the reservoir (or at least if their interfacial tension and wettability characteristics are similar). Otherwise a weighing factor must be applied, the ratio of the products $\sigma.\cos\theta$ (see above § 1-1.2.5)

We therefore obtain the saturation distribution shown on Figure 1-1.50b. We observe the three zones mentioned earlier (§ 1-1.2.2.C, p. 56), i.e. from top to bottom (decreasing capillary pressure):

– The saturation zone at maximum Pc ("irreducible" according to the former terminology) where the wetting phase (water) confined in the finest menisci is non-movable (the relative water permeability is zero). This zone where anhydrous oil is produced corresponds to the reservoir in the common meaning of the term. The main practical

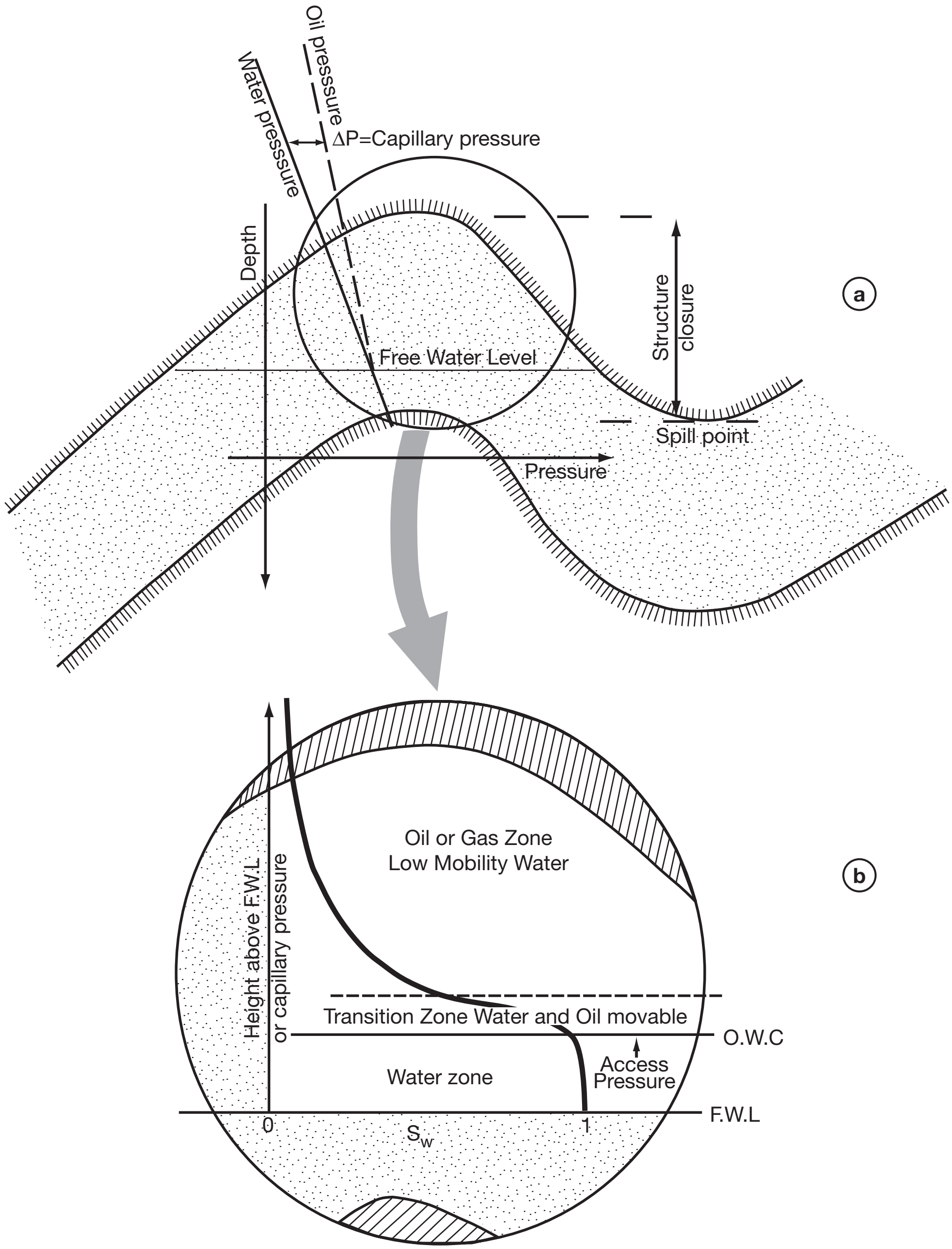


Figure 1-1.50 Distribution of fluids in a reservoir
a) Pressure profile in water and hydrocarbon, definition of the Free Water Level (FWL).
b) Standard saturation profile.

problem arising with this zone is how to determine the value of S_{wi}, a matter of great concern for reservoir specialists. We will discuss this subject briefly in § 1-2.3.3, p. 186.

– The transition zone where the two phases are movable (relative water and oil permeabilities non zero). The bottom of this zone corresponds to the appearance of hydrocarbons in the reservoir. This is the original (before start of production) oil-water contact (OOWC) or gas-water contact (OGWC) which could be quite different from the free water level (FWL).
– The capillary foot (or capillary drag). This is a very special zone, totally water saturated, but in which the (virtual) capillary pressure is non zero. The pore throat radius is too narrow for the non-wetting fluid to enter. In practical reservoir geology applications, this zone is of considerable interest to provide an insight into original oil/water contact (OOWC) anomalies.

c) Some simple examples of numerical values

We saw in § 1-1.2.5 that we can estimate the scale conversion factor to graduate the capillary pressure axis in heights above FWL, to obtain the diagram of a saturated reservoir. To simplify matters, we will use mercury porosimetry curves as capillary pressure value ($\dagger_s$ = 460 mN/m, θ = 140°). Although this may not be the best way to investigate the notion of S_{wi}, it is sufficient for our purposes, where the main objective is to examine the capillary feet and the original oil/water contacts (OOWC). We will study a standard water/oil ($\dagger_s$ = 30 mN/m, θ = 0°, Δρ = 200 kg/m^3) and water/gas ($\dagger_s$ = 50 mN/m, θ = 0°, Δρ = 700 kg/m^3) case (see Table 1-1.7, p. 55).

On Figure 1-1.51, the maximum height scale (500 m) corresponds to the major petroleum zones (remember that the height of the hydrocarbon column may exceed one kilometre in some fields (e.g. the Middle East)).

At this scale, we mainly observe that:

– The water/hydrocarbon contacts (OWC, GWC) correspond to the free water level (y = 0 on Figure 1-1.51) for all the "permeable" reservoirs (single-phase permeability greater than several tens of millidarcy). There is no difference between OOWC and FWL when we consider the traditional sandstone reservoirs or the permeable carbonate reservoirs. This explains the sometimes marked lack of interest for this problem. In contrast, the "capillary foot" zone may take on considerable importance when dealing with very low permeability reservoirs, especially micrite type limestone reservoirs but also poorly porous sandstone reservoirs.
– Obviously, due to the larger density difference, the problems of FWL/GWC shift are less significant in gas reservoirs.
– As soon as we start to move up in the structure, the water saturation gradient as a function of the height is low, even with the simple calculation mode used (directly related to the porosimetry access radii).

We must remember that these remarks apply to a high oil column (important structuration **and** abundance of hydrocarbons). For "poor" petroleum provinces, the problems may be quite different, for example for stratigraphic traps (see § C. a and b below*)*.

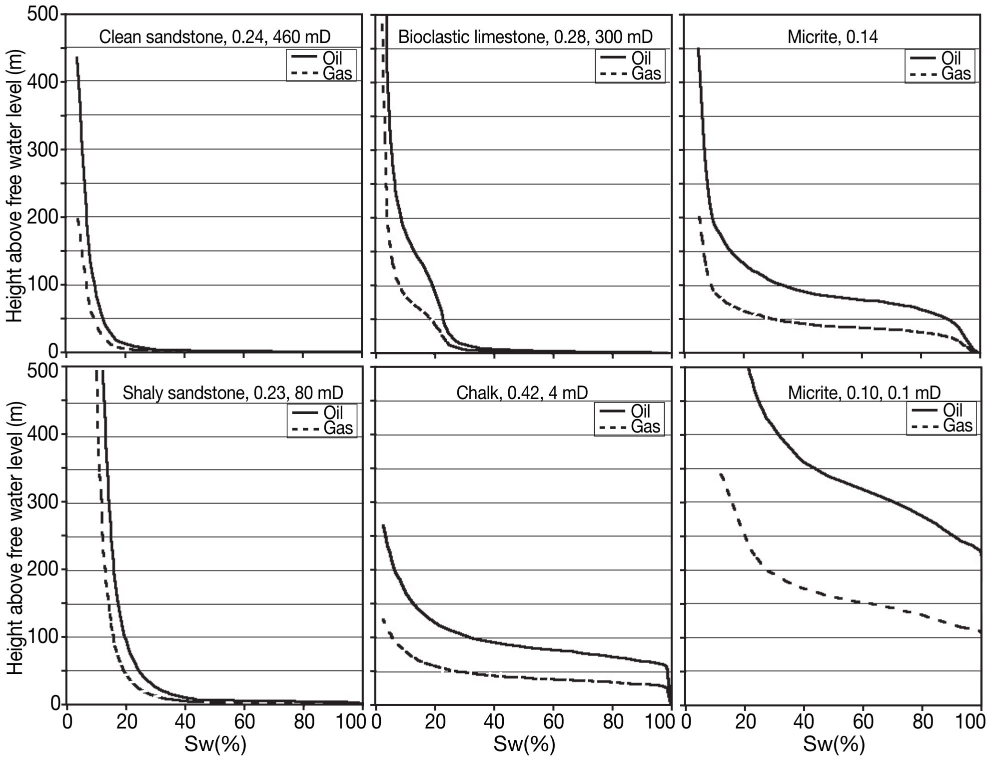


Figure 1-1.51 Examples of saturation profiles

C) Applications to some practical aspects of reservoir geology

The above description of fluid distribution corresponds to the idealised case of a perfectly homogeneous reservoir, both in terms of the petrophysical properties of the rock and those of the saturating fluids. In nature, the situation is never that simple. The first cause of complexity is due to the fact that natural reservoirs are heterogeneous. In this paragraph, we will discuss a few cases of reservoir geology where the application of these simple capillary equilibrium notions helps us to understand the phenomena involved.

a) Water/oil contact fluctuations

Determination of the water/oil contact and the free water level

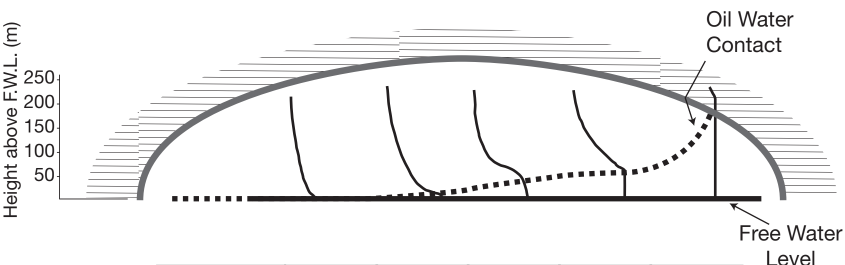
As soon as we move away from the case of permeable reservoirs with zero transition zone, determining the exact value of these two levels may be less trivial than it would first appear.

Determining the original oil/water contact corresponds to the appearance of the first oil indices, which are not always easy to detect using log analysis in cases of low porosity and saturation. There are two ways to determine the free water level: either by identifying the oil/water contact in a drain with zero capillarity (in practice, an observation well left idle for a long period of time), or by measuring the pressure gradient in oil through mini-tests carried out at various depths (repetitive tests). Conducted according to professional standards both methods are expensive and consequently, when discussing real field cases, data uncertainty must always be taken into account.

Fluctuations due to petrophysical variations (fixed FWL)

General case

Imagine a large limestone reservoir changing, due to sedimentological evolution, from porous bioclastic grainstones to increasingly compact micritic formations exhibiting the petrophysical characteristics described on Figure 1-1.52. While the free water level (FWL) remains horizontal and stable throughout the structure, the original oil/water contact (OOWC) follows the value equivalent to the access pressure. In the assumption of Figure 1-1.52, the altitude of the water "level" increases from left (bioclastic grainstone) to right (compact micrite). To plot the curves shown on Figure 1-1.52 we adopted the standard oil characteristics used in the previous paragraph. The values are therefore representative. We observe that for the second saturation profile (pelletoidal grainstone) which still corresponds to a reservoir rock, there is already a shift of some ten metres. For the third and fourth profiles, the shifts reach several tens of metres.



	1	2	3	4	5
ϕ K (mD)	0.33 300	0.23 7	0.22 1	0.15 03	0.10 0.01

Figure 1-1.52 Diagram of irregular hydrocarbon/water contact related to the lateral variation of the reservoir

Obviously, the example shown on Figure1-1.52 is highly diagrammatic. It is based mainly on an assumption of vertical homogeneousness. To return to a more realistic situation, we would have to introduce vertical variability in order to show "superimposed" water levels. This example nevertheless clearly shows that the notion of a flat and horizontal water level, so frequently encountered in permeable reservoirs, is completely meaningless as soon as we are faced with poorly permeable reservoirs, of micrite type for example.

Whenever we observe a fluctuation in water level, we must first consider the assumption of a petrophysical variation.

Case of fractured reservoirs

The saturation profiles 3 and 4 shown on Figure 1-1.52 correspond to poorly permeable reservoirs which will only yield good production if a network of open fractures creates high-permeability drains. These matrices, poorly permeable but still exhibiting high porosity, and therefore very oil-rich in the zones above the water "level", can supply the network of fractures. Some of the most productive oil fields in the world operate according to this scheme.

One important feature of open fracture networks must be pointed out. These fractures exhibit "conducting apertures" up to several hundred microns thick. As a result, they are no longer subject to capillarity and the oil/water contact corresponds to the free water level. We therefore observe in these reservoirs two different oil/water contacts, sometimes several tens of metres apart, corresponding to the two media of highly contrasted petrophysical properties, which coexist in these reservoirs (Fig.1-1.53). Since the open fractured medium represents only a minute fraction of the total porous medium, the oil it contains is impossible to detect using log analysis. Occasionally, some water saturated reservoir zones (matrix) yield excellent oil production if an open fracture intersects the well. However, this production only lasts as long as the open fracture network is "supplied" with oil… but this is outside the scope of our subject!

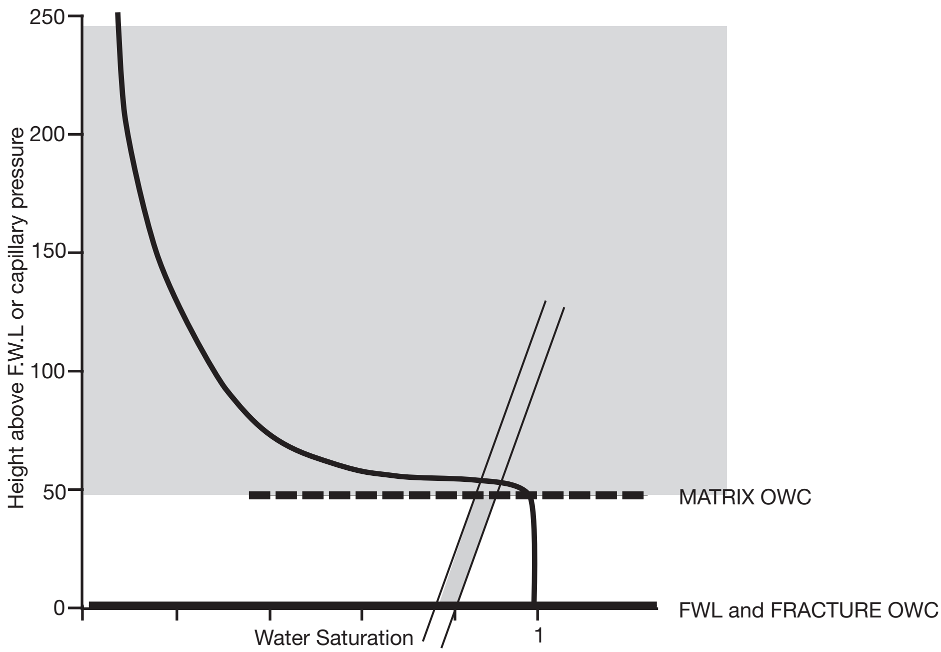


Figure 1-1.53 Position of the oil/water contact in fractured reservoirs

Extreme case of fluctuation of petrophysical origin: the stratigraphic trap

If we look at the fifth saturation profile on Figure 1-1.52, the access pressure of this very fine micrite corresponds to a height of more than 200 m above free water level. If the reservoir closure is less than this high value, the rock is totally water saturated and acts as a cap rock. If we imagine that the type 5 rock corresponds to a lateral facies variation upwards, in a monoclinal structure, we obtain a perfect example of stratigraphic trap. The stratigraphic trap corresponds to the extreme stage of petrophysical fluctuation of the water level.

We mentioned that this rock would act as capillary barrier (and therefore as cap rock) as long as the closure is not high enough to induce a capillary pressure greater than the access pressure. If the capillary pressure increases up to this threshold, then the "barrier" layer is invaded by oil and, at least theoretically, the oil previously trapped can escape across the "ex-barrier" and continue its secondary migration. We would therefore observe a geological equivalent of the penetration by the non-wetting fluid through the semi-permeable membrane in a restored state experiment (§ 1-1.2.4, p. 73).

Unlike the case of shaly cap rock, the notion of cap rock in "stratigraphic trap" is often related to the height of the oil column in the zone concerned. In shaly cap rocks, the access pressure is often more than one hundred bars (which corresponds to a 5 km oil column, according to our calculation assumption) and we may speak of absolute capillary barrier.

Fluctuations related to pressure variations

In the previous paragraph, we considered the case of a stable hydrostatic state and variable petrophysical properties. We will now investigate an opposite situation in which a pressure variation leads to a variation in OOWC (in a homogeneous petrophysical reservoir). Pressure variations are induced by two main causes.

Pressure variations related to hydrodynamism

The logic we outlined above is based on the rules of hydrostatics, i.e. it assumes pressure equilibrium, especially in the aquifer which acts as implicit reference. If the aquifer is active, in other words if there is a pressure gradient in the horizontal plane causing a flow, the free water level will be inclined in the same direction as the aquifer isobar lines. It will be "tilted" in the direction of flow (Fig. 1-1.54). This pressure variation is easy to calculate for a given aquifer flow. We will express this flow as filtration velocity (U). Remember (§ 1-2.1.1, p. 125) that the filtration velocity does not correspond to the displacement velocity of the water particles but to the total quantity of water which crossed a plane normal to the flow during the chosen reference period. The corresponding hydraulic gradient (in bar/cm) is equal to this velocity in cm/s divided by the permeability in darcy (definition of the darcy).

To use more "practical" units, we will say that a filtration velocity of 1 m/year corresponds to a gradient of about 300 millibar/km in a rock of permeability 1 D. In large captive water tables of high permeability, the filtration velocity is less than 1 m/year (Table 1-2.1, p. 126). We may therefore consider that this value is an upper limit of the situation found at shallow depths in terms of petroleum criteria.

The difference in depth (Δh) of the free water level induced by this hydrodynamic pressure variation (ΔP) is given by the hydrostatic formula: $\Delta h = \Delta P / \Delta \rho \gamma$. This value can be

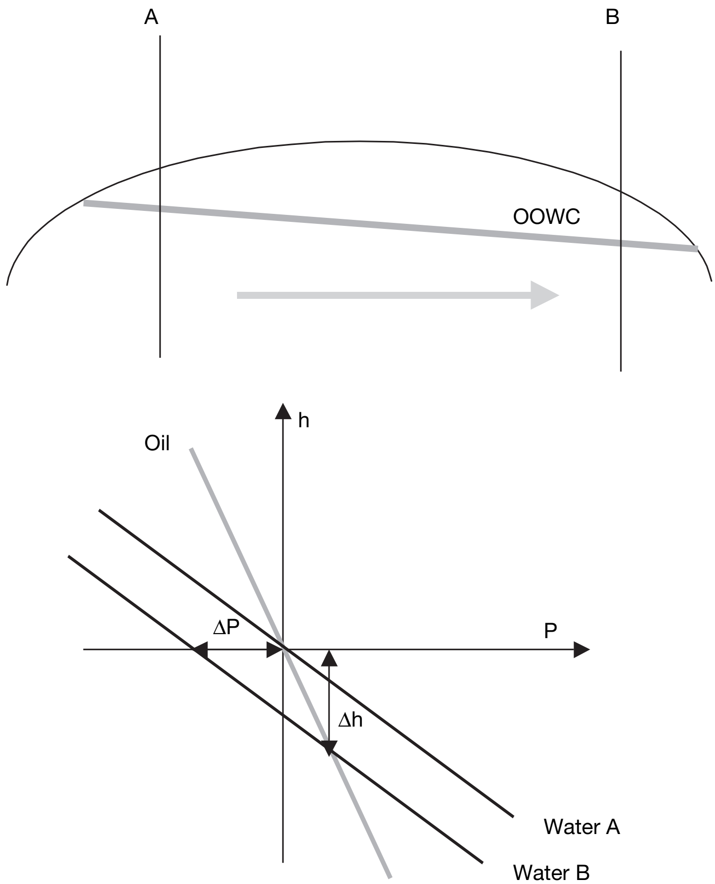


Figure 1-1.54 Hydrocarbon/water contact inclined due to hydrodynamism

checked graphically on diagram 1-1.54 where ΔP is clearly the capillary pressure at height Δh on the vertical B. In the extreme case of a filtration velocity of 1 m/year, the difference on the free water level value is therefore about 15 m/km, which corresponds to a very high gradient on the oil/water contact.

However, the filtration velocity values corresponding to the reservoir aquifers are much smaller. In a conventional oil field, therefore, the difference in water level related to "reasonable" hydrodynamism will be much less than 1 m per kilometre.

Hydrodynamism comes back from time to time as a possible explanation for water level "tilting". In our opinion this is often unjustified. The hydrodynamic explanation of "tilt" in the water level must be limited to very shallow reservoirs located on aquifers proven to be highly active. At the very least, we must avoid the absurdity of using hydrodynamism to explain a "tilt" associated with an aquifer with such little activity that water would have to be injected to maintain production.

Pressure variations related to modifications of the fluid types

We have seen that the main cause of the pressure difference between water and oil was the difference in their densities ($Pc = \Delta\rho\gamma h$). If a given reservoir is spread out geographically, however, density variations may be caused by a number of factors. These factors include (non exhaustive list – several factors may be found in the same reservoir):

– variation in oil type or gas content;
– variation in water salinity;
– variation in temperature under the effect of a geothermal variation.

Calculating the effect of these variations on the free water level and on the oil/water contact is more difficult than in the previous case since assumptions must be made, on a case by case basis, regarding the location of the pressure constants chosen as reference.

To give an example, Stenger [1999] used a temperature/salinity variation to explain a tilt of about 0.5 m/km in the FWL on the Ghawar field (Saudi Arabia). Note that this variation is only important since it extends over several hundred kilometres in this field, the largest in the world.

b) Anhydrous production in zones of high water saturation

In conventional permeable reservoirs, anhydrous oil production zones are generally associated with zones of lower water saturation This corresponds to the fact that the zones of high saturation can only be transition zones in which the water is movable. This rule does not apply in some reservoirs.

The extreme example of this problem was discussed when we mentioned earlier the case of fractured reservoirs producing under the water level corresponding to the matrix.

This phenomenon may be observed in a more “subtle” way, at matrix scale, in limestone reservoirs exhibiting highly contrasted double porosity (micro/macro – see Glossary Index). Figure 1-1.55 shows the epoxy pore cast (§ 2-2.1, p. 331) of an oolitic limestone exhibiting both significant intraoolitic microporosity, contributing in particular to the high porosity (0.34), and a well-developed intergranular macroporosity, inducing very high permeability (600 mD). The porosimetry curve, converted into saturation profile for a standard water/oil pair, indicates that at 25 m above free water level, the water saturation is about 0.5 (and 0.40 at 75 m). This high water saturation corresponds to almost non-movable water in the microporosity and the rock may yield abundant anhydrous production. This observation is particularly important for zones of low hydrocarbon column.

This represents a further example of the petrophysical features associated with the double matrix media encountered so frequently in carbonate rocks. This is why, during exploration phases, it is often recommended to carry out a systematic test of the porous limestone layers, irrespective of the saturation data obtained by log analysis.

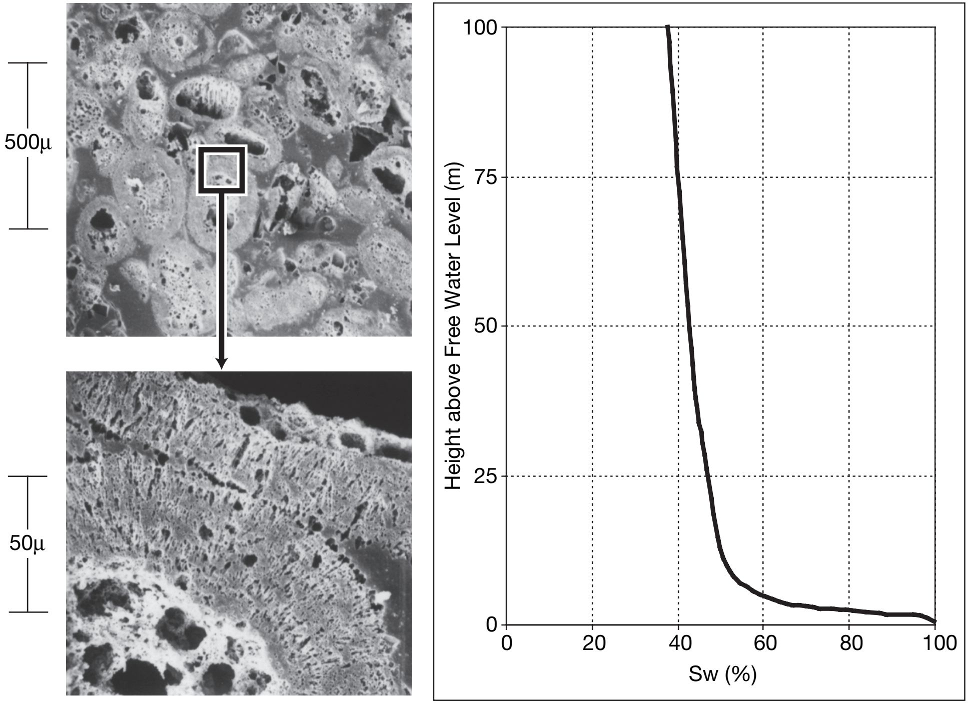


Figure 1-1.55 Example of reservoir which could exhibit anhydrous oil production in a zone with high Sw: capillary pressure curve and epoxy pore cast observed under electron microscope